SPECIFIED GAS EMITTERS REGULATION

QUANTIFICATION PROTOCOL FOR INSTRUMENT GAS TO INSTRUMENT AIR CONVERSION IN PROCESS CONTROL SYSTEMS

OCTOBER 2009

Version 1.0

Alberta

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All Quantification Protocols approved under the *Specified Gas Emitters Regulation* are subject to periodic review as deemed necessary by the Department, and will be re-examined at a minimum of every 5 years from the original publication date to ensure methodologies and science continue to reflect best-available knowledge and best practices. This 5-year review will not impact the credit duration stream of projects that have been initiated under previous versions of the protocol. Any updates to protocols occurring as a result of the 5-year and/or other reviews will apply at the end of the first credit duration period for applicable project extensions.

Any comments, questions, or suggestions regarding the content of this document may be directed to:

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Date of Publication: October 2009

ISBN: 978-0-7785-8791-0 (Printed)
ISBN: 978-0-7785-8792-7 (On-line)

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1.0 Project and Methodology Scope and Description

This quantification protocol is written for the gas and/or oil operator or any operator in the oil and gas industry where natural gas is used to provide pressure for process control systems. Some familiarity with, or understanding of, the operation of gas and/or oil operations and control systems is assumed.

Wells, oil producing and gas producing facilities, and gas processing facilities sometimes use pneumatic devices for process control. Pneumatic instruments may be powered by compressed air, natural gas, or propane. Readily available pressurized natural gas has made it the power source of choice among operators in the industry. Natural gas is used to power process control equipment, which includes pressure controllers, temperature controllers, transducers, liquid level controllers, and flow rate regulators. These devices have one or two emission rates depending on the design: continuous or bleed rate and intermittent or vent rate. Once the gas has powered the instrument, it is left to vent and bleed to the atmosphere. The vent and bleed rate will depend on the type of device, age and operating condition. For the purpose of this protocol, the sum of these two emission rates will be referred to as **vent rate or vented gas**, which is the term commonly used in the oil and gas industry. Bleed rate or bleed gas is also used in industry to express the sum of these two emissions.

The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reduction of greenhouse gas emissions resulting from the conversion of instrument gas to instrument air in process control systems. Instrument air will be provided by compressed air. Therefore, a complete air compressor system will be needed for this conversion.

It must be stated that this protocol does not stipulate a process change but rather a change in the pressure source for typical process control systems. It is assumed that a natural gas pressure source will be converted to an air pressure source. It should be noted that any volume that would have been vented will now be avoided by this conversion. The final fate of the gas may be assumed to be combustion by end-users, unless otherwise indicated.

1.1 Protocol Scope and Description

This protocol serves as a generic 'recipe' for project proponents to follow in order to meet the measurement, monitoring, and greenhouse gas quantification requirements for reductions resulting from conversion of instrument gas to instrument air in process control systems. A process flow diagram for a typical project using compressed air to provide pressure to instrument controllers is shown in **FIGURE 1.1.** Upon conversion, all methane that would have been vented will be replaced by compressed air.

Protocol Approach:

The baseline condition for this protocol is defined as the volume of natural gas vented or flared/combusted to the atmosphere prior to the conversion to instrument air. In this baseline scenario, instrument gas is typically sourced from the fuel supply for the entire facility. This is a major source of greenhouse gas emissions for the baseline. A process flow diagram for a typical baseline using fuel gas to provide pressure to pneumatic controllers is shown in **FIGURE 1.2.** Other sources of emission include greenhouse gases from fuel extraction and processing.

In the baseline condition, vented, or flared/combusted gas is typically not metered. Establishing volumes of vented, or flared/combusted gas will have to be performed by converting metered volumes of air to volumes of gas through an equivalency. This protocol therefore uses data from metered air to establish the volume of natural gas that would have been vented, or flared/combusted had the project not taken place. Further explanation of how to establish this equivalency is **APPENDIX A.1**. Establishing the amount of compressed air for the project will depend on the facility implementing the air conversion system. For facilities installing an air compressor system to power pneumatic instruments, metering air is straightforward. Metered air will provide volumes that can be used to establish emissions from:

1) Equivalent fuel gas vented, or flared/combusted; and
2) Emissions from fuel gas extraction and processing.

However, some facilities may have an air compressor system already installed for other applications. In such cases, air consumed by the pneumatic instruments will have to be prorated against total air compressed.

Prorated quantities may also be re-conciliated quantities on a periodic basis. In other words, a balance can be carried out to determine the quantities used in air compression.

Equations have been developed in order to quantify these emissions from the project and baseline conditions. These equations have been developed considering choked conditions in the pneumatic devices. This assumption yields equations that are accurate, yet underestimate emissions. This is a conservative approach and assures that emissions are not overestimated. In addition, this assumption makes the protocol easy to use and data collection simple and manageable. Refer to **APPENDIX A.1** for more details.

Metering will be carried out for a minimum period of **ONE** year for compressed air. Emissions from this period are assumed to be **representative** of normal instrument operations during the project and baseline conditions. Furthermore, since control instruments work at a steady rate in a given facility, this period of metering will reflect a static condition for both the baseline and the project for the reporting period. This protocol therefore assumes that the baseline and project condition are static, unless adjusted. The one year metering period ensures a conservative approach. This is because leaks are prone to appear in pneumatic systems over time. Therefore by setting the baseline close to the leak inspection and repair program, and for a period of time of one

year, the risk of overestimating measured emissions is reduced. Furthermore, the longer the system is metered the increased likelihood that these quantities include leaks.

To facilitate verification, the project proponent should identify the run time of principle equipment such as compressors, dehydrators, or other equipment within the facility to show continuity and typical runtimes. The runtime of this equipment in subsequent years should be compared to the hours it operated during the period of one year metering. The percentage difference is then applied against the offsets calculated for that year to account for any variations in facility operation.

Protocol Applicability:

To demonstrate that a project meets the requirements under this protocol, the project developer must supply sufficient evidence to demonstrate that:

1. Pneumatic instruments are designed to operate using a pressurized gas (i.e. 20 or 35 psi for commercially available devices), regardless of the gas type. As a result, the instrument air system must be designed to provide this same level of pressure that the instrument gas system would have provided to ensure functional equivalency as demonstrated by unit operationalperformance data, and/or facility process flow diagrams and/or other equipment technical specifications. Functional equivalence may also be demonstrated through an affirmation by the project developer or a third party.

2. The project is a conversion from instrument gas to instrument air and not facilities originally constructed to use instrument air or replacements due to end-of-life. This may be demonstrated by facility process flow diagrams and/or accounting records, work orders, invoices or other vendor/third party documentation/evidence. Instrument air conversions may also be demonstrated through an affirmation by the project developer or a third party.

3. To facilitate verification and allow for changes in the facility, the proponent will develop an inventory of devices to be maintained annually. Any changes to the inventory, i.e. devices removed, will impact net offsets claimed as illustrated in **APPENDIX B.3**. The list will also help in determining what fraction of the pneumatic devices was vented and what fraction was flared. Refer to the flexibility mechanism section and **APPENDIX B** for more details.

4. The key concept in this applicability criterion is for the project proponent to inspect and repair leaks prior to actual metering to reduce and mitigate risks associated with overestimation of emissions.

   Prior to the implementation of the instrument air system and metering, the project proponent must demonstrate that the instrument air system's piping network has been inspected for leaks as pursuant to section 8.7 in Directive 60. This directive 60 states that an operator of an oil or gas facility must develop and implement a program to detect and repair leaks meeting or exceeding the CAPP *Best*

Management Practice (BMP) for Fugitive Emissions Management. This BMP suggests annual or quarterly leak monitoring frequencies depending on the process equipment device. Following these steps should guarantee that leaks have been minimized as much as practically possible. This will ensure that metering does not overestimate volumes of air, which in turn determines the volumes of gas that would have been vented, had the project not taken place. If inspection for leaks is not performed according to suggested monitoring frequencies, metered air must be reduced using a Discount Factor. This factor is developed in detail in **APPENDIX A.2**.

For projects installed prior to this protocol that are currently not metered, the same principle applies as detailed above. Prior to the installation of a metering system, leaks should be minimized as much as practically possible.

5. This protocol has been designed for specific use in natural gas processing plants. However, other facilities in the oil and gas industry use instrument gas to provide pressure to pneumatic devices. This protocol may be applied to projects where existing gas provides pressure to instrumentation or Chemical Injection Pumps (CIP), or other types of equipment.

6. The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System. [Of particular note:

    a. [The date of equipment installation, operating parameter changes or process reconfiguration are initiated or have effect on the project on or after January 1, 2002 as indicated by facility records;]
    b. [The project may generate emission reduction offsets for a period of 8 years unless an extension is granted by Alberta Environment, as indicated by facility and offset records. Additional credit duration periods require a reassessment of the baseline condition; and,]
    c. [Ownership of the emission reduction offsets must be established as indicated by facility records.]

Protocol Flexibility:

Flexibility in applying the quantification protocol is provided to project developers in the following ways:

1. Site specific emissions factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must be sufficiently robust to ensure accuracy.

2. Baseline and project metering may be carried out for more than one year if the project proponent deems necessary to show more accurate and representative emissions. It is up to the project proponent to justify this flexibility mechanism.

3. For cases in which projects were implemented but the air was not metered, carbon offsets are claimable. This claim is based on instrument counts from the facility and the metered air. Emissions from the one year metering are used as a baseline. This baseline is adjusted by subtracting the sum of the devices added multiplied by their respective vent rate. Details of this flexibility mechanism are provided in **APPENDIX B.1**. It should be noted that the lists in **APPENDIX B** are not complete lists and therefore not authoritative. More instruments may exist or are under development and have not been included. These lists only serve as an illustrative example of the emissions that may be encountered by project developer. It is up to the project developer to use emission or vent rates that are most current by contacting the manufacturer of specific devices and request information for those specific devices. Manufacturers of control devices usually publish the emission rates for each type of device, and for each type of operation.

4. For projects where part of the vented gas is flared or collected for combustion, the project proponent may claim credits using this protocol's flexibility mechanism. The total metered air is divided into two fractions; X represents the vented fraction and (1-X) represents the flared or combusted fraction. X represents a fraction that is established using vendor's technical specifications for bleed rates (BR). Refer to **APPENDIX B.2** for a detailed explanation on how these percentages are established. Assuming all instrument gas is vented, the value of X is 1.

5. Instrument air conversions can be installed at single or multiple sites. As such, the protocol allows for flexibility in quantifying offsets from multiple conversion projects. If applicable, the proponent must indicate and justify why flexibility provisions have been used.

1.2 Glossary of New Terms

Instrument Air	Any instrument that uses pressurized compressed air to function and provided the necessary level of control required for its intended use.
Bleed Rate	Rate at which a device uses air or natural gas continuously due to design requirements. Rates may vary in the field due to changing conditions.
Fuel Gas	Portion of the sales gas used for facility operations such as fuel for engines and compressors, pressure supply for pneumatic devices, etc…
Functional Equivalence	The project and the baseline should provide the same function and quality of products or services. This type of comparison requires a common metric or unit of measurement (such as flow rate) for comparison between the Project and Baseline activity (Refer to the Guidance Document for the Alberta Offset System). Pneumatic instruments are designed to operate using a pressurized gas (i.e. 20 or 35 psi for commercially available devices), regardless of the gas type.

	As a result, the instrument air system must be designed to provide this same level of pressure that the instrument gas system would have provided to ensure functional equivalency.
Instrument Gas	Any instrument that uses pressurized natural gas to function and provided the necessary level of control required for its intended use.
Leak	Unwanted emissions from worn seals, gaskets, and diaphragms, nozzle corrosion or wear from poor quality gas leading to increased flow, and loose control tube fittings in a pneumatic instrument
Vent Rate	Rate at which a device uses air or natural gas intermittently due to design requirements. Rates may vary in the field due to changing conditions. In this protocol, vent rate is used to describe the sum of both bleed and vent rates.

FIGURE 1.1: Process Flow Diagram for Project Condition

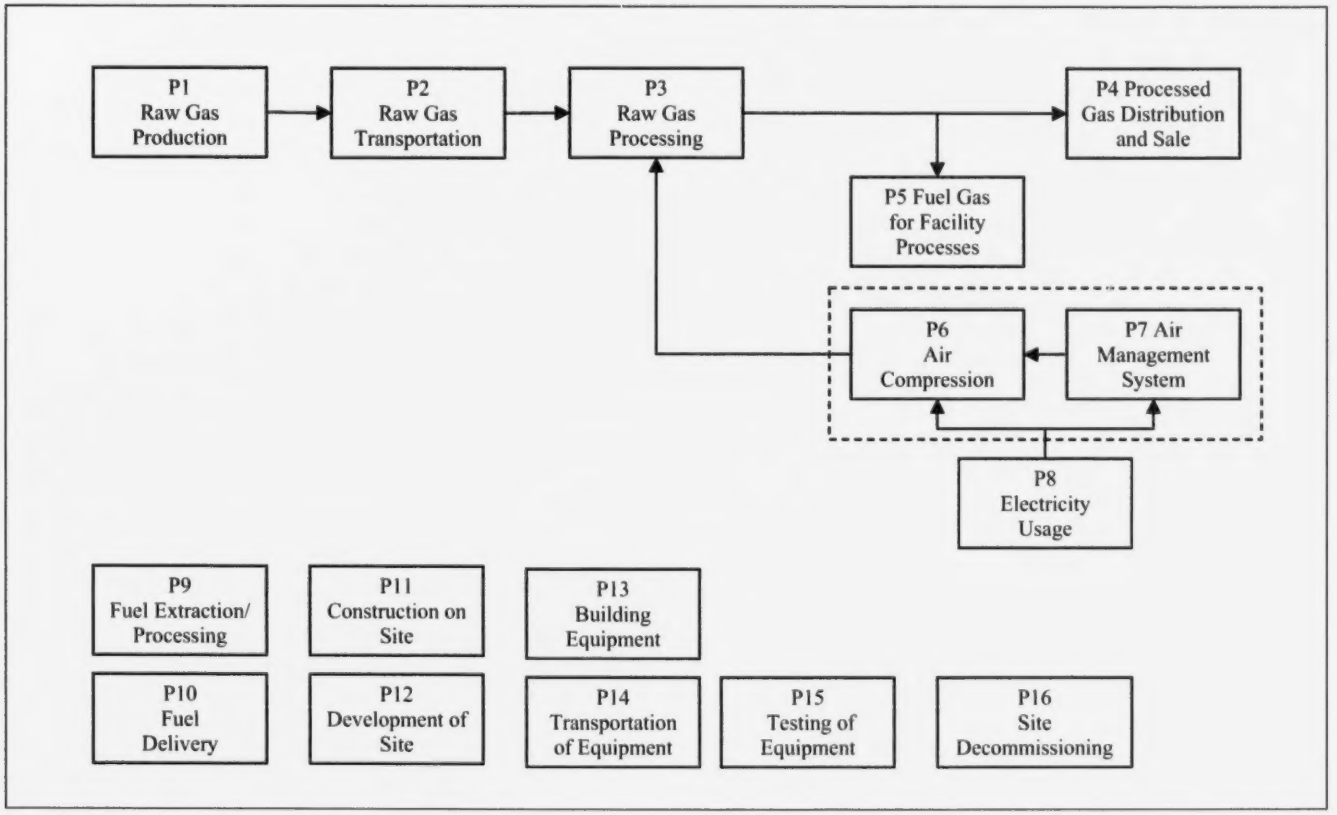
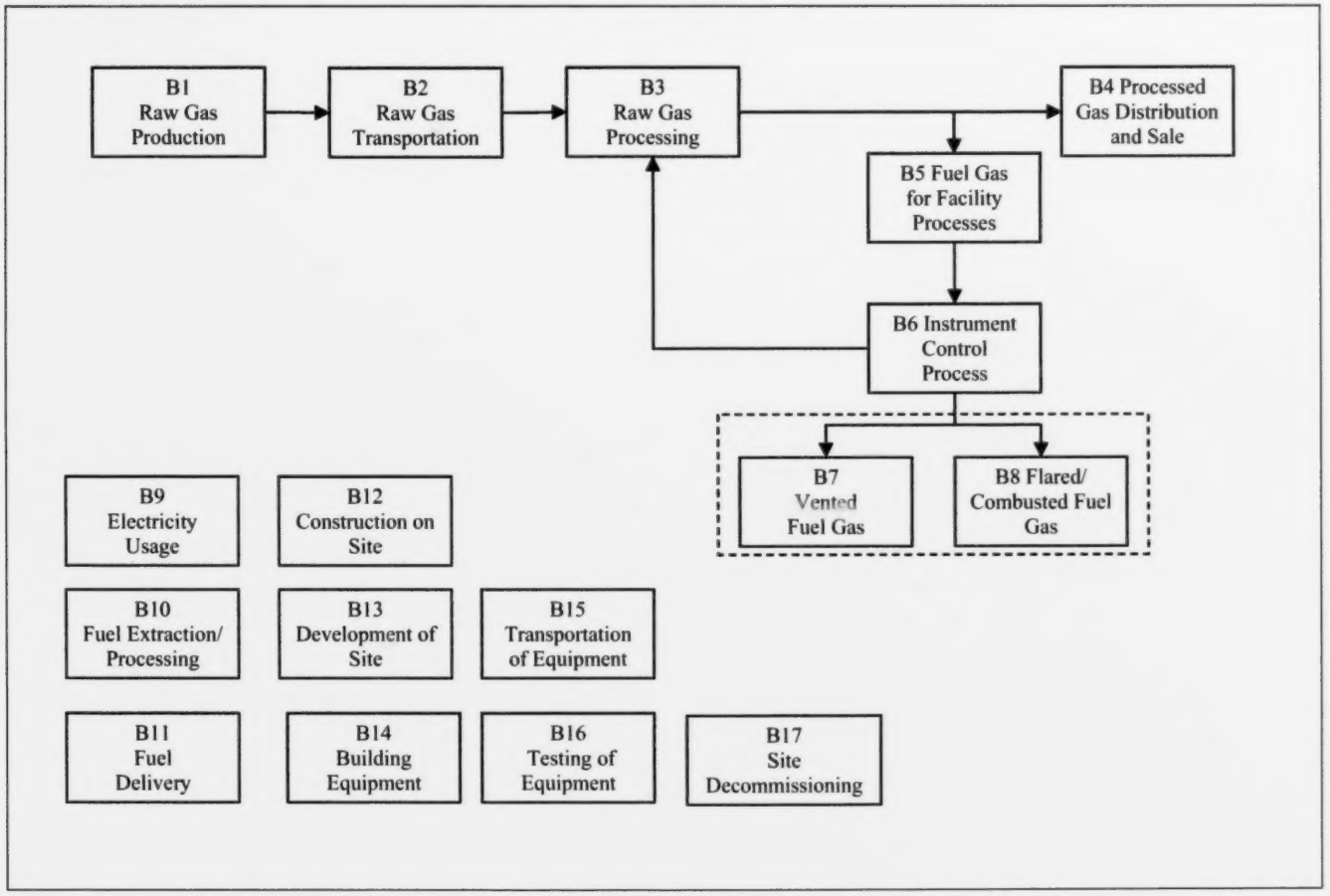


FIGURE 1.2: Process Flow Diagram for Baseline Condition



2.0 Quantification Development and Justification

The following sections outline the quantification development and justifications.

2.1 Identification of Sources and Sinks (SS's) for the Project

SS's were identified for the project by reviewing the seed documents and relevant process flow diagrams pertaining to the operation of natural gas processing facilities. This process confirmed that the SS's in the process flow diagrams covered the full scope of eligible project activities under the protocol.

Based on the process diagrams provided in **FIGURE 1.1**, the project's SS's were organized into life cycle categories in **FIGURE 1.1**, Description of each of the SS's and their classification as controlled, related or affected are provided in **TABLE 1.1**.

FIGURE 1.1: Project Element Life Cycle Chart

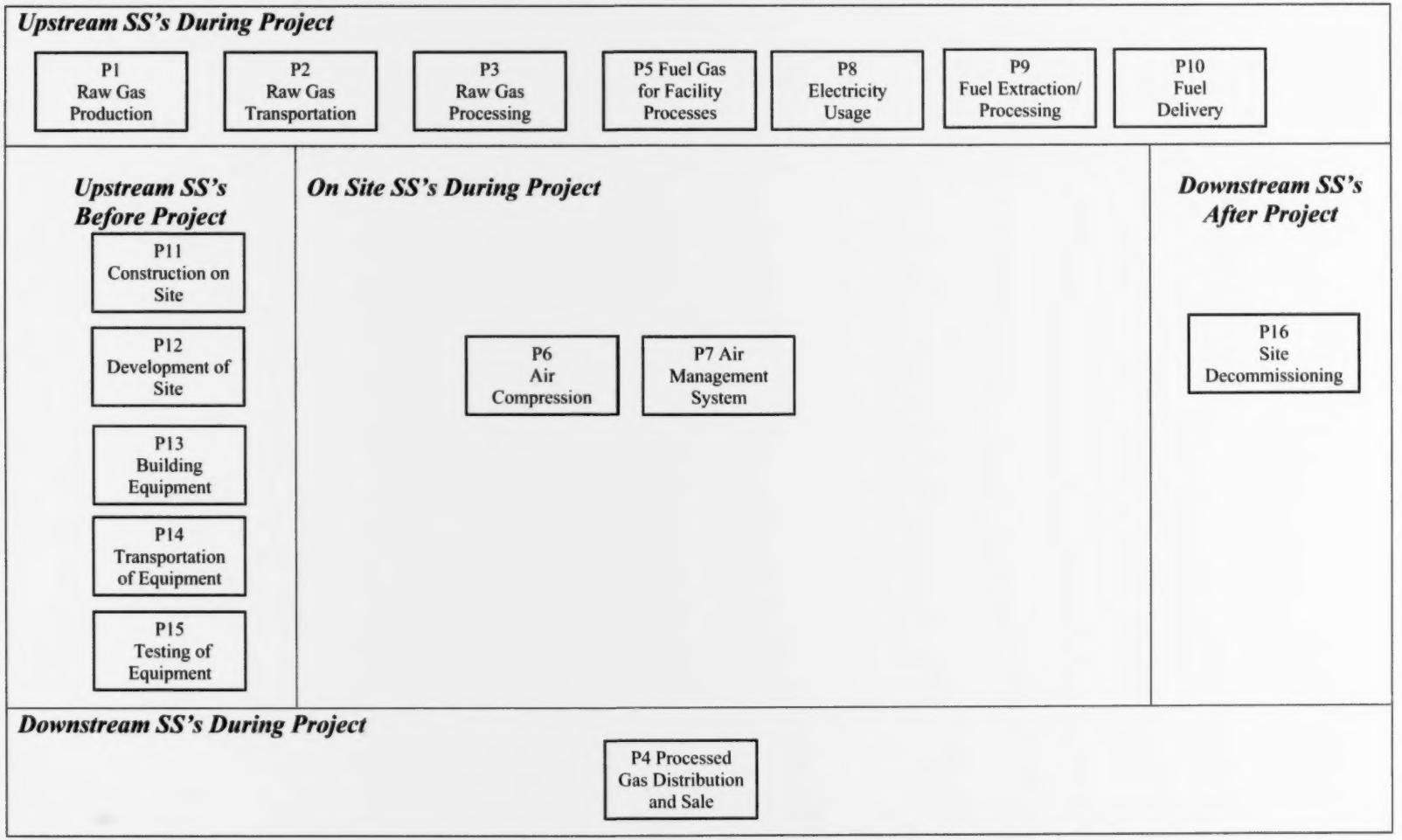

Upstream SS's During Project
P1 Raw Gas Production
P2 Raw Gas Transportation
P3 Raw Gas Processing
P5 Fuel Gas for Facility Processes
P8 Electricity Usage
P9 Fuel Extraction/ Processing
P10 Fuel Delivery
Upstream SS's Before Project
P11 Construction on Site
P12 Development of Site
P13 Building Equipment
P14 Transportation of Equipment
P15 Testing of Equipment
On Site SS's During Project
P6 Air Compression
P7 Air Management System
Downstream SS's After Project
P16 Site Decommissioning
Downstream SS's During Project
P4 Processed Gas Distribution and Sale

TABLE 1.1: Project SS's

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Project Operation		
P1 Raw Gas Production	The raw gas is collected from a group of adjacent wells where moisture content is reduced by removing water and condensate. Condensate is transported to oil refineries for further processing and wastewater is disposed. The quantity of greenhouse gases in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would also need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
P2 Raw Gas Transportation	The raw gas is piped to a natural gas processing plant. The types and quantities of fuels used in transportation would need to be tracked. Leaks may also be present in the pipeline and should be tracked also.	Related
P3 Raw Gas Processing	Processing of raw gas is required to remove hydrogen sulphur, carbon dioxide, water vapour, and heavier hydrocarbons. Clean gas is ready to be distributed and sold. Heavier hydrocarbons are also removed and transported to oil refineries. The quantity of greenhouse gas in the processed gas would need to be tracked. Leaks may also be present in the production facility and should be tracked too. Possibility of venting gas must also be considered and tracked.	Related
P5 Fuel Gas For Facility	Many processes in the facility require clean gas to function. This clean gas, also referred to as fuel gas, is drawn from the processed gas that will be sold. Equipment in the processes includes compressors, boilers, heaters, engines, glycol dehydrators, refrigerators, and chemical injection pumps (CIP). The types and quantities of fuels used in processing would need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
P8 Electricity Usage	Electricity may be required for operating the facility. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of the power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions. For facilities located near the electricity grid, P6 and P7 will most likely use this electricity source. Electricity for P6 and P7 for facilities located in remote areas may include fossil fuels such as diesel or natural gas.	Related
P9 Fuel Extraction/ Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of greenhouse gas emissions from the various processes involved in the production, refinement, and storage of the fuels. The total volumes of fuel for each of the SS's in this project are considered in this SS. Types and quantities of fuels used would need to be tracked.	Related

P10 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's and there is no other delivery.	Related
Onsite SS's during Project Operation		
P6 Air Compression	Air will be used to supply pressure to the pneumatic control instruments. The energy required for the compressors to function will come from various sources. Quantity and source of the electricity source are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Controlled
P7 Air Management System	Compressed air will pass from the air compressor to the volume tanks and then through the control instrumentation when activated. This air may require conditioning such as drying by specialized equipment prior to distribution in the air instrument network. Equipment for the air management system may consume energy and needs to be tracked.	Controlled
Downstream SS's during Project Operation		
P4 Processed Gas Distribution and Sale	Natural gas and other commercially viable NGL products may be sent to a pipeline system or transported by rail or truck to customers at another point. Avoided greenhouse gas emissions from the fuel gas supply to the control instrumentation should be included here. It is assumed that the mostly likely use of avoided greenhouse gas emissions would be controlled combustion to produce carbon dioxide.	Related
Other		
P11 Construction on Site	The process of construction at the site may require a variety of heavy equipment, smaller power tools, cranes, and generators. The operation of this equipment will have associated greenhouse gas emissions from the use of fossil fuels and electricity.	Related
P12 Development of Site	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
P13 Building of Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control, and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabrication and assembly.	Related

P14 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by train, truck, barge, or by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
P15 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity	Related
P16 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

2.2 Identification of Baseline

The baseline condition for projects applying this protocol is defined as the operating condition prior to the conversion of instrument gas to instrument air. The baseline is site specific and depends on the facility operation. Baseline fuel venting from pneumatic controls depends on the type of pneumatic device, operating condition, age, among other factors.

The most accurate method to establish a baseline is to meter vented fuel gas from individual devices. However, this is not a standard practice in industry because it can be time consuming, resource intensive, and costly. As a result, baseline emissions are determined from the metered quantity of compressed air through a gas equivalence formula as described in **APPENDIX A**. Once the air has been metered, the gas equivalency is applied. This will yield the amount of fuel gas that would have been vented. Note that this equivalency is in terms of pure methane (100% in gas composition). The equivalent volume is then be adjusted so it can take into account the percent of methane and carbon dioxide present in this fuel gas based on an annual gas analysis.

The aforementioned baseline approach is justified as follows. Pneumatic devices are designed to run at a specific supply pressure, regardless of the pressure source. In the gas equivalency formula presented in **APPENDIX A**, pressure is assumed to be equal in the instrument gas and instrument air condition. To solve the gas equivalency formula, both fuel gas and air pressure are assumed to be equal. Therefore when the formula is solved, the energy loss in both the fuel gas and air condition is equal. This allows us to establish a relationship between the volume of air in the project condition and the volume of fuel gas in the baseline condition. As a result, this baseline methodology ensures functional equivalence because pressures in baseline and project conditions are assumed to be equal. Furthermore, this is an industry-accepted methodology to compare air and fuel gas emissions.

It must be noted that the fuel gas used to power the pneumatic instruments is not raw gas, but rather processed natural gas. Therefore, the equivalent volume is used to estimate the emissions from extraction and processing of raw gas.

The baseline condition is defined, including the relevant SS's and processes, as shown in **FIGURE 1.2**. More detail on each of these SS's is provided in the following section, section 2.3.

2.3 Identification of SS's for the Baseline

Based on the process diagrams provided in **FIGURE 1.2,** the project's SS's were organized into life cycle categories in **FIGURE 1.2**. Description of each of the SS's and their classification as 'controlled', 'related' or 'affected are provided in **TABLE 1.2**.

FIGURE 1.2: Baseline Element Life Cycle Chart

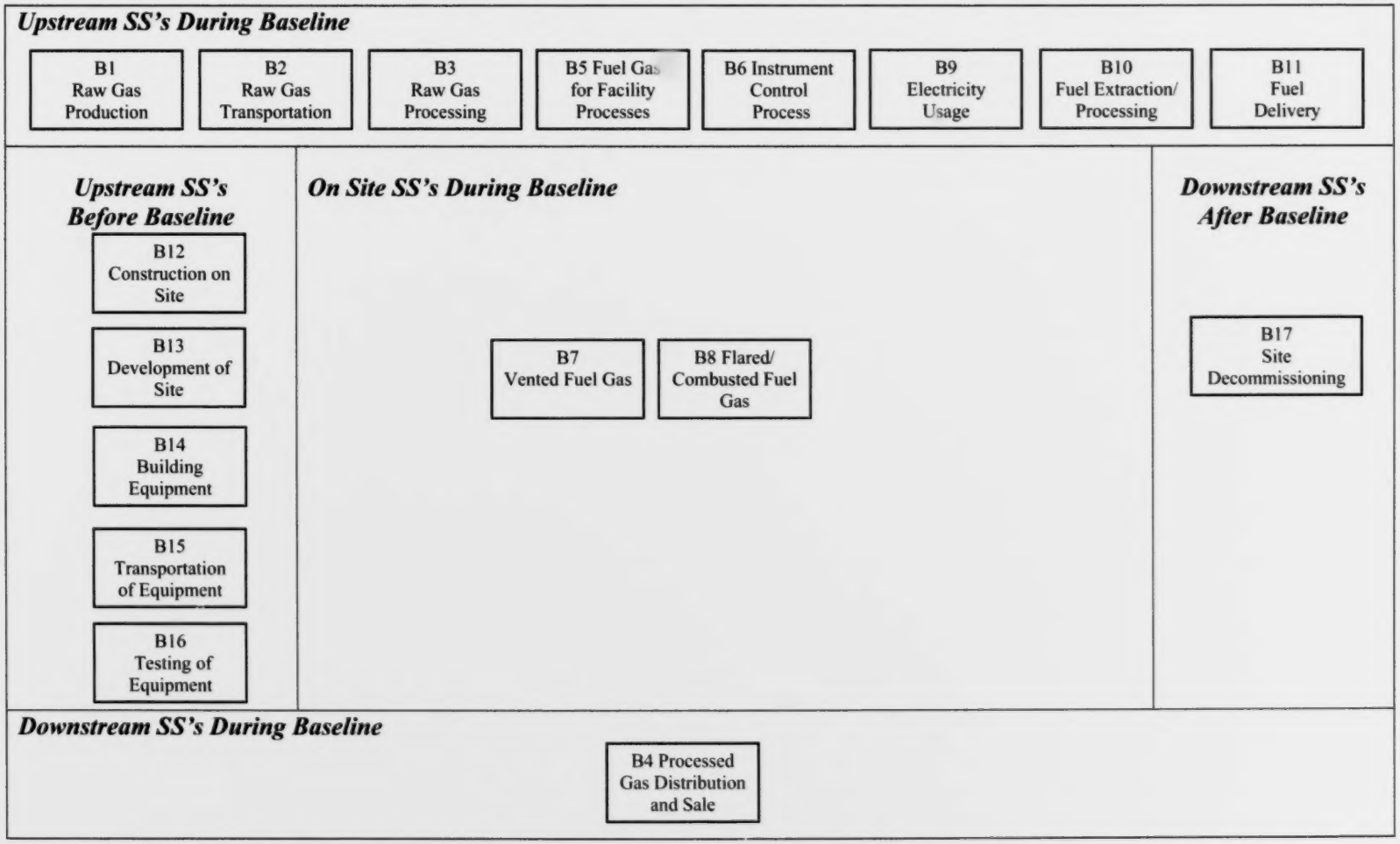

Upstream SS's During Baseline
B1 Raw Gas Production
B2 Raw Gas Transportation
B3 Raw Gas Processing
B5 Fuel Gas for Facility Processes
B6 Instrument Control Process
B9 Electricity Usage
B10 Fuel Extraction/ Processing
B11 Fuel Delivery
Upstream SS's Before Baseline
B12 Construction on Site
B13 Development of Site
B14 Building Equipment
B15 Transportation of Equipment
B16 Testing of Equipment
On Site SS's During Baseline
B7 Vented Fuel Gas
B8 Flared/ Combusted Fuel Gas
Downstream SS's After Baseline
B17 Site Decommissioning
Downstream SS's During Baseline
B4 Processed Gas Distribution and Sale

TABLE 1.2: Baseline SS's

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Baseline Operation		
B1 Raw Gas Production	The raw gas is collected from a group of adjacent wells where moisture content is reduced by removing water and condensate. Condensate is transported to oil refineries for further processing and wastewater is disposed. The quantity of greenhouse gas in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would also need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
B2 Raw Gas Transportation	The raw gas is piped to a natural gas processing plant. The types and quantities of fuels used in transportation would need to be tracked. Leaks may also be present in the pipeline and should be tracked also.	Related
B3 Raw Gas Processing	Processing of raw gas is required to remove hydrogen sulphur, carbon dioxide, water vapour, and heavier hydrocarbons. Clean gas is ready to be distributed and sold. Heavier hydrocarbons are also removed and transported to oil refineries. The quantity of greenhouse gas in the processed gas would need to be tracked. Leaks may also be present in the production facility and should be tracked too. Possibility of venting gas must also be considered and tracked.	Related
B5 Fuel Gas For Facility	Many processes in the facility require clean gas to function. This clean gas, also referred to as fuel gas, is drawn from the processed. Equipment in the processes include compressors, boilers, heaters, engines, glycol dehydrators, refrigerators, and chemical injection pumps (CIP), The types and quantities of fuels used in processing would need to be tracked. Leaks may also be present in the production facility and should be tracked too.	Related
B6 Instrument Control Process	Pressurized gas will pass from the fuel gas supply and then through the control instruments when activated. The pressure of the gas is equivalent to the pressure that the project will provide to the instruments once the conversion has taken place.	Controlled
B9 Electricity Usage	Electricity may be required for operating the facility. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of the power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Related
B10 Fuel Extraction/ Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of greenhouse gas emissions from the various processes involved in the production, refinement, and storage of the fuels. The total volumes of fuel for each of the SS's in this project are considered in this SS. Types and quantities of fuels used would need to be tracked.	Related

B11 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gas. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's and there is no other delivery.	Related
Onsite SS's during Baseline Operation		
B7 Vented Fuel Gas	Quantity of gas will need to be tracked because it represents the amount of fuel gas that is vented to the atmosphere once it has been used by pneumatic instruments. The quantity can be calculated or estimated.	Controlled
B8 Flared/ Combusted Fuel Gas	Quantity of gas will need to be tracked because it represents the amount of fuel gas that might be collected and sent to a flare or combustion source. The quantity can be calculated or estimated.	Controlled
Downstream SS's during Baseline Operation		
B4 Processed Gas Distribution and Sale	Natural gas and other commercially viable NGL products may be sent to a pipeline system or transported by rail or truck to customers at another point. The mostly likely use would be controlled combustion to produce carbon dioxide.	Related
Other		
B12 Construction on Site	The process of construction at the site may require a variety of heavy equipment, smaller power tools, cranes, and generators. The operation of this equipment will have associated greenhouse gas emissions from the use of fossil fuels and electricity.	Related
B13 Development of Site	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
B14 Building of Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control, and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabrication and assembly.	Related
B15 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by train, truck, barge, or by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related

B16 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related
B17 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

2.4 Selection of Relevant Project and Baseline SS's

Each of the SS's from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the exclusion or conditions upon which SS's may be excluded is provided in **TABLE 1.3**, below. All other SS's listed previously are included.

TABLE 1.3: Comparison of SS's

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
Upstream SS's				
P1 Raw Gas Production	N/A	Related	Excluded	Excluded as the production of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B1 Raw Gas Production	Related	N/A	Excluded	
P2 Raw Gas Transportation	N/A	Related	Excluded	Excluded as the transportation of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B2 Raw Gas Transportation	Related	N/A	Excluded	
P3 Raw Gas Processing	N/A	Related	Excluded	Excluded as the processing of raw gas is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B3 Raw Gas Processing	Related	N/A	Excluded	
P5 Fuel Gas For Facility	N/A	Related	Excluded	Excluded as the fuel gas for facility is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B5 Fuel Gas For Facility	Related	N/A	Excluded	
P9 Fuel Extraction/ Processing	N/A	Related	Included	N/A
B10 Fuel Extraction/ Processing	Related	N/A	Included	N/A
P8 Electricity Usage	N/A	Related	Excluded	Excluded as these SS's are not relevant to the project as the emission from these practises are covered under proposed greenhouse gas regulations.
B9 Electricity Usage	Related	N/A	Excluded	Fuel gas processing does not use electricity in this case.
P10 Fuel Delivery	N/A	Related	Excluded	Excluded as the fuel delivery is not impacted by the implementation of the project and as such the baseline and the project conditions will be functionally equivalent.
B11 Fuel Delivery	Related	N/A	Excluded	
Onsite SS's				
P6 Air Compression	N/A	Related	Included	N/A
P7 Air Management System	N/A	Related	Included	N/A
B7 Vented Fuel Gas	Related	N/A	Included	N/A
B8 Flared/ Combusted	Related	N/A	Included	N/A

Fuel Gas				
Downstream SS's				
P4 Processed Gas Distribution and Sale	N/A	Related	Excluded	Excluded as the emissions from the distribution and sale of avoided vented gas is the sole responsibility of the end user. It is assumed the final use of this gas will be controlled combustion to produce carbon dioxide. Accountability of this gas is in the hands of end users.
B4 Processed Gas Distribution and Sale	Related	N/A	Excluded	Excluded as the emissions from the distribution and sale of gas is the sole responsibility of the end user and it is assumed the final use of this gas will be controlled combustion to produce carbon dioxide.
Other				
P11 Construction on Site	N/A	Related	Excluded	Emissions from construction on site are not material given the long project life and the minimal construction on site typically required.
B12 Construction on Site	Related	N/A	Excluded	Emissions from construction on site are not material for the baseline condition given the minimal construction on site typically required.
P12 Development of Site	N/A	Related	Excluded	Emissions from development of site are not material given the long project life and the minimal development of site typically required.
B13 Development of Site	Related	N/A	Excluded	Emissions from development of site are not material for the baseline condition given the minimal development of site typically required.
P13 Building of Equipment	N/A	Related	Excluded	Emissions from building of equipment are not material given the long project life and the minimal building equipment typically required.
B14 Building of Equipment	Related	N/A	Excluded	Emissions from building of equipment are not material for the baseline given the minimal building equipment typically required.
P14 Testing of Equipment	N/A	Related	Excluded	Emissions from testing of equipment are not material given the long project life and the minimal testing of equipment typically required.
B15 Testing of Equipment	Related	N/A	Excluded	Emissions from testing of equipment are not material for the baseline given the minimal testing of equipment typically required.
P15 Transportation of Equipment	N/A	Related	Excluded	Emissions from transportation of equipment are not material given the long project life and the minimal transportation of equipment typically required.
B16 Transportation of Equipment	Related	N/A	Excluded	Emissions from transportation of equipment are not material for the baseline given the minimal transportation of equipment typically required.
P16 Site Decommissioning	N/A	Related	Excluded	Emissions from decommissioning of site are not material given the long project life and the minimal decommissioning typically required.
B17 Site Decommissioning	Related	N/A	Excluded	Emissions from decommissioning of site are not material for the baseline given the minimal decommissioning typically required.

2.5 Quantification of Reduction, Removals, and Reversals of Relevant SS's

2.5.1 Quantification Approach

Quantification of the reductions, removals and reversals of relevant SS's for each of the greenhouse gases will be completed using the methodologies outlined in **TABLE 1.4**, below. These calculation methodologies serve to complete the following three equations for calculating the emission reductions from the comparison of the baseline and project conditions.

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Vented Fuel Gas}} + \text{Emissions}_{\text{Flared/Combusted Fuel Gas}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Air Compression}} + \text{Emissions}_{\text{Air Management System}}$$

where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions under the baseline condition.
$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS B10 Fuel Extraction and Processing
$\text{Emissions}_{\text{Vented Fuel Gas}}$ = emissions under SS B7 Vented Fuel Gas
$\text{Emissions}_{\text{Flared/Combusted Fuel Gas}}$ = emissions under SS B8 Flared/Combusted Fuel Gas

$\text{Emissions}_{\text{Project}}$ = sum of the emissions under the project condition.
$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS P9 Fuel Extraction and Processing
$\text{Emissions}_{\text{Air Compression}}$ = emissions under SS P6 Air Compression
$\text{Emissions}_{\text{Air Management System}}$ = emissions under SS P7 Air Management System

TABLE 1.4: Quantification Procedures

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P9 Fuel Extraction/ Processing	Emissions $_{\text{Fuel Extraction / Processing}}$ = Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CO2}$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CH4}$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,N2O}$)					
	Emissions $_{\text{Fuel Extraction / Processing}}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Volume of Fossil Fuel i Combusted for P 6 and P 7 / Vol. Fuel $_i$	m^3	Measured	Direct metering or reconciliation of volumes	Annual	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{CO2}$	kg CO_2 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH_4 Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_2O Emissions Factor for Fuel Including	kg N_2O per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

	Production and Processing / EF Fuel $_{N20}$					reporting on Canada's emissions inventory.
P6 Air Compression	*The following equation (1) should be used to calculate emissions from Air Compression for projects that use on-site electricity generated from fossil fuels.* 1. Emissions $_{\text{Air Compression}}$ = Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CO2}$*Compressed Air $_{\text{Control Instruments i}}$) / Σ (Total Produced Air $_i$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CH4}$*Compressed Air $_{\text{Control Instruments i}}$) / Σ (Total Produced Air $_i$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,N2O}$*Compressed Air $_{\text{Control Instruments i}}$) / Σ (Total Produced Air $_i$)					
	Emissions $_{\text{Air Compression}}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Compressed Air Used for Pneumatic Instrument $_i$ / Compressed Air $_{\text{Control Instruments i}}$	m^3	Measured	Direct metering of volume being compressed and sent to control instrument pipe network	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Total Air Produced in Air Compressor System by Compressor i / Produced Air $_i$	m^3	Measured	Direct metering of volume being compressed	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Volume of Fossil Fuel i Combusted for P 6 to Produce Electricity for the Air Compression	m^3	Measured	Direct metering or reconciliation of volumes	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of

	System/ Vol. Fuel $_i$					reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor Each Type of Fuel i / EF Fuel $_{CO2}$	kg CO_2 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH_4 Emissions Factor for Each Type of Fuel i / EF Fuel $_{CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel i / EF Fuel $_{N2O}$	kg N_2O per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
P7 Air Management System	*The following equation (1) should be used to calculate emissions from Air Management System for projects that use on-site electricity generated from fossil fuels.* 1. Emissions $_{\text{Air Management System}}$ = Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CO2}$*Managed Air $_{\text{Control Instruments i}}$) / Σ (Total Managed Air $_i$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,CH4}$*Managed Air $_{\text{Control Instruments i}}$) / Σ (Total Managed Air $_i$); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\,N2O}$*Managed Air $_{\text{Control Instruments i}}$) / Σ (Total Managed Air $_i$).					
	Emissions $_{\text{Air Compression}}$	kg of COe_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Managed Air by	m^3	Measured	Direct metering of	1 year	Both methods are

	Air Management system i / Managed Air $_{Control\ Instruments\ i}$			volume being managed and sent to control instrument pipe network	continuous metering	standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Total Air Managed by Air Management System i/ Total Managed Air $_{i}$	m^3	Measured	Direct metering of volume being managed	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	Volume of Fossil Fuel i Combusted for P7 to Produce Electricity for the Air Management System/ Vol. Fuel $_{i}$	m^3	Measured	Direct metering or reconciliation of volumes	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor Each Type of Fuel i / EF Fuel $_{CO2}$	kg CO_2 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH_4 Emissions Factor for Each Type of Fuel i / EF Fuel $_{CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel i / EF	kg N_2O per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

	Fuel $_{N2O}$					reporting on Canada's emissions inventory.
Baseline SS's						
B10 Fuel Extraction/ Processing	Emissions $_{Fuel\ Extraction\ /\ Processing}$ = Σ (Emissions $_{Fuel\ Gas\ for\ Control\ Instruments}$ * EF Fuel $_{i\ CO2}$); Σ (Emissions $_{Fuel\ Gas\ for\ Control\ Instruments}$ * EF Fuel $_{i\ CH4}$); Σ (Emissions $_{Fuel\ Gas\ for\ Control\ Instruments}$ * EF Fuel $_{i\ N2O}$)					
	Emissions $_{Fuel\ Extraction\ /\ Processing}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
	Volume of Fossil Fuel i Consumed for B7 and B8 / Emissions $_{Fuel\ Gas\ for\ Control\ Instruments}$	m^3	Estimated	Estimated based on volumes from B 7 and B 8	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{CO2}$	kg CO_2 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH_4 Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_2O Emissions Factor for Fuel Including	kg N_2O per m^3	Estimated	From Environment Canada reference documents	Annual	Reference values adjusted annually as part of Environment Canada

<table>
<tr><td></td><td>Production and Processing / EF Fuel $_{N2O}$</td><td></td><td></td><td></td><td></td><td>reporting on Canada's emissions inventory.</td></tr>
<tr><td>B7 Vented Fuel Gas</td><td colspan="6">The following equations are used to establish baseline emissions based on metered compressed air powering the pneumatic instruments once the air conversion has taken place. Equation (1) is for the vented CH_4 and will always be used. Typically, the percentage of CH_4 in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for ventedCO_2. If the percentage of CO_2 is in excess of 10%, equation (2) is used to establish baseline CO_2 emissions from vented fuel. If the percentage of CO_2 emissions is inferior to 10%, it is advisable not to include CO_2 emissions as the volumes are insignificant.

1. Emissions $_{\text{Fuel Gas for Control Instruments}}$ =
$$\Sigma \text{ Compressed Air}_{\text{Control Instruments i}} * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4};$$
2. $$\Sigma \text{ Compressed Air}_{\text{Control Instruments i}} * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16};$$
where
$$F_k = \frac{k}{1.4}$$</td></tr>
<tr><td></td><td>Emissions $_{\text{Fuel Gas For Control Instruments}}$</td><td>kg of CH_4 ; CO_2</td><td>N/A</td><td>N/A</td><td>N/A</td><td>Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.</td></tr>
<tr><td></td><td>Compressed Air Used for</td><td>m^3</td><td>Measured</td><td>Direct metering of volume being</td><td>1 year continuous</td><td>Both methods are standard practice.</td></tr>
</table>

	Pneumatic Instruments $_i$/ Compressed Air Control Instruments i			compressed and sent to control instrument pipe network as determined in P6	metering	Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence. Values must be adjusted for standard temperature and pressure STP.[1]
	Discount Rate due to Leaks / DR	%	Estimated	1. DR(%)=0 if inspection occurred ≤ 1 year 2. DR(%)= 2.5 %*minimum year interval for 1< year ≤ 10 3. DR(%)= 25% for year > 10	N/A	Leaks are taken into account when air is metered to adjust the baseline. The year of last documented inspection and maintenance is taken into account in parameter 'minimum year interval'. A 2.5% per annum increase due to leaks is assumed.
	Specific Gravity of Air /G_{AIR}	-	Estimated	1.00 at NTP	N/A	Accepted value.
	Specific Gravity of Methane / G_{CH4}	-	Estimated	0.5537 at NTP	N/A	Accepted value.
	Density of Methane / ρ_{CH4}	Kg / m^3	Estimated	0.717kg/m^3 at STP	N/A	If this value is used all values must be adjusted for standard temperature and pressure STP.

[1] The pressure at which the instrument air system operates under steady state conditions is constant and is found in the design considerations of the compressed air system.

	Specific Heat Ratio for CH_4 / k_{CH4}	-	Assumed	1.31 at STP	N/A	Accepted value.
	Specific Heat Ratio for air /1.4	-	Assumed	1.40 at STP	N/A	Accepted value.
	Methane Composition in Fuel Gas / % CH_4	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation.
	Carbon Dioxide Composition in Fuel Gas / % CO_2	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation.
B8 Flared/Combusted Fuel Gas	Refer to Flexibility Mechanism for details (Appendix B.2)					

2.5.2 Contingent Data Approach

Contingent means for calculating or estimating the required data for the equations outlined in section 2.5.1 are summarized in **TABLE 2.5**, below.

2.6 Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigor of the management system data, the more easily an audit will be to conduct for the project.

2.6.1 Record Keeping

Record keeping practices should include:

a. Electronic recording of values of logged primary parameters for each measurement interval;
b. Printing of monthly back-up hard copies of all logged data;
c. Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
d. Retention of copies of logs and all logged data for a period of 7 years; and
e. Keeping all records available for review by a verification body.

2.6.2 Quality Assurance/Quality control (QA/QC)

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

a. Protecting monitoring equipment (sealed meters and data loggers);
b. Protecting records of monitored data (hard copy and electronic storage);
c. Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
d. Comparing current estimates with previous estimates as a 'reality check';
e. Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
f. Establish minimum experience and requirements for operators in charge of project and monitoring; and
g. Perform recalculations to make sure no mathematical errors have been made.

TABLE 1.5: Contingent Data Collection Procedures

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P9 Fuel Extraction and Processing	Volume of Fossil Fuel i Combusted for P6 and P7 Type of Fuel / Vol. Fuel $_i$	L / m^3 / other	Estimated	Reconciliation of volume of fuel purchased within given time period	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
P6 Air Compression	Volume of Fossil Fuel i Combusted for P6 to Produce Electricity for the Air Compression System/ Vol. Fuel $_i$	L / m^3 / other	Estimated	Reconciliation of volume of fuel purchased within given time period	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Compressed Air Used for Pneumatic Instruments / Compressed Air Control Instruments i	m^3	Estimated	Reconciliation of compressed air used in air compression system within given time period based on equipment efficiency specifications and average flow rates	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Total Air Produced in Air Compressor System by Compressor i / Produced Air $_i$	m^3	Estimated	Reconciliation of total air produced in air compression system within given time period based on equipment efficiency specifications and average flow rates	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.

P7 Air Management System	Volume of Fossil Fuel i Combusted for P7 to Produce Electricity for the Air Management System/ Vol. Fuel $_i$	L / m^3 / other	Estimated	Reconciliation of volume of fuel purchased within given time period	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Managed Air by Air Management system i / Managed Air $_{\text{Control Instruments i}}$	m^3	Estimated	Reconciliation of managed air used in air management system within given time period based on equipment efficiency specifications and average flow rates	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Total Air Managed by Air Management System i/ Total Managed Air $_i$	m^3	Estimated	Reconciliation of managed air used in air management system within given time period based on equipment efficiency specifications and average flow rates	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
Baseline SS's						
B10 Fuel Extraction and Processing	Volume of Fossil Fuel i Consumed for B7 and B8 / Emissions $_{\text{Fuel Gas for Control Instruments}}$	m^3	Estimated	Estimated based on volumes from B 7 and B 8	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
B7 Vented Fuel Gas	Compressed Air Used for Pneumatic Instruments / Compressed Air $_{\text{Control Instruments i}}$	m^3	Estimated	Reconciliation of compressed air used in air compression system within given time period based on equipment efficiency specifications	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.

				and average flow rates		
	Methane Composition in Fuel Gas / % CH_4	%	Estimated	From accredited references or industry standards	Annually	Estimating gas composition from accredited references provides a reasonable estimate when the more accurate method cannot be used.
	Carbon dioxide Composition in Fuel Gas / % CO_2	%	Estimated	From accredited references or industry standards	Annually	Estimating gas composition from accredited references provides a reasonable estimate when the more accurate method cannot be used.

APPENDIX A - Explanation on Gas Equivalency and Leaks

A.1 Gas Equivalence

The capacity of a device to flow air or gas is expressed in terms of C_V, or flow coefficient. The C_V measures the impact on flow from diverse factors to a device such as:

- Orifice size (diameter of the piping or opening through the valve);
- Length of piping or opening through the valve;
- Turbulence caused by bends or turns in the piping;
- Restrictions, or anything that reduces the orifice size or the flow path; and
- Shape of the orifice.

For this protocol, the formula employed by the Instrument Society of America (ISA) based on L.R. Driskell's work will be used to develop equivalence between air consumption and natural gas that would have been consumed. This formula may be found in *ANSI/ISA-75.02-1996 Control Valve Capacity Test Procedures* and is an established method used by industry to calculate the C_V for pneumatic devices. Expanded formula can be found in L.R. Driskell's *New approach to Control Valve Sizing*.

Gas and air are considered compressible fluids. In pneumatic devices, flow can be choked or non-choked. Flow in a duct or passage such that the flow upstream of a certain critical section cannot be increased by a reduction of downstream pressure is defined as choked. For the purpose of this protocol, choked conditions will be used because these conditions represent a conservative approach in estimating air volumes, explained in detail in this section.

For compressible fluid flow in non-choked conditions, the flow rate can be expressed as

$$Q_{SCFH} = 4.17 * C_V * P_{1psia} * Y \sqrt{\frac{x}{G_g * T_{\circ R}}} \qquad (1)$$

where

$$Y = 1 - \frac{x}{3 * F_k * X_T} \qquad \text{(Limits } 1.0 \geq Y \geq 0.667 \text{ for air)} \qquad (2)$$

Q_{SCMH} = fluid volumetric flow rate (m^3/h);
C_V = flow coefficient;
P_{1kPa} = inlet pressure;
Y = expansion factor;
x = pressure drop ratio to absolute inlet pressure
G_g = gas specific gravity (this is the density of the gas divided by the density of air at the same conditions);
$T_{\circ K}$ = temperature in degrees Kelvin;
F_k = ratio of specific heats (equal to the specific heat ratio of the gas divided by the specific heat ratio of air); and
X_T = maximum pressure ratio before choking.

When choking occurs, (1) and (2) are still valid with the exception that $x=X_T$. Equation (2) becomes

$$Y = 1 - \frac{1}{3 * F_k} \tag{3}$$

where

$$F_k = \frac{k}{1.4}$$

k is the ratio of specific heats for a given gas (1.4 is the ratio specific heat for air, 1.3 for methane). The **heat capacity ratio** or **adiabatic index** or **ratio of specific heats**, is the ratio of the heat capacity at constant pressure (C_P) to heat capacity at constant volume (C_V). It is the ratio of specific heats between 2 gases; in the case of the protocol, the ratio between air and air (used as reference), and the ratio between methane and air, the gas of interest.

Approach

In order to establish the equivalence of how much natural gas would have been vented if the air system had not been installed, the assumption of equal C_V for both gas and air powered devices must be established. Therefore (1) for CH_4 can be expressed as

$$Q_{CH4} = 4.17 * C_V * P_{1kPa} * Y_{CH4} * \sqrt{\frac{x}{G_{CH4} * T_{\circ K}}} \tag{4}$$

where

Q_{CH4} = CH_4 volumetric fluid flow rate

Similarly, (1) for air can be expressed as

$$Q_{AIR} = 4.17 * C_V * P_{1kPa} * Y_{AIR} * \sqrt{\frac{x}{G_{AIR} * T_{\circ K}}} \tag{5}$$

where

Q_{AIR} = air volumetric flow rate

It should be noted that a specific pneumatic instrument has a unique C_v, regardless of the liquid or gas being consumed by the instrument. By substituting (5) into (4) as a function of C_V and eliminating common terms,

$$Q_{CH4} = Q_{AIR} * \frac{1}{\sqrt{\frac{1}{G_{AIR}}}} * \frac{1}{Y_{AIR}} * Y_{CH4} * \sqrt{\frac{1}{G_{CH4}}} \quad (6)$$

The fuel gas supply and compressed air will travel along the same pipe network. Pressures cancel each other out since they are assumed equal as per the consideration of functional equivalence ($P_{1kPa\ AIR} = P_{1kPa\ CH4}$).

Because the pipeline is thin and not insulated, the temperature of the gas (either fuel supply gas or air) will reach approximate ambient temperature just before being vented by the pneumatic device after having travelled through the pipe network ($T_{AIR}=T_{CH4}$). For this reason, the temperatures of either fuel gas or compressed air were considered comparable and cancel each other out in equation (6).

Finally, x was taken as x_T or the limiting condition when choking occurs. If YC_v is plotted against x, there is a linear relationship with a negative slope as x increase. Choked condition will occur when $Y*C_v=.667*C_v$ for air and $Y*C_v=.644*C_v$ for methane. Note that the corresponding values of $x_{T\ AIR}$ when $Y*C_v=.667*C_v$ is slightly less than the corresponding value of $x_{T\ CH4}$ when $Y*Cv=.644*C_v$ for a given device. When dividing $x_{T\ CH4}$ by $x_{T\ AIR}$ and square-rooting, this value is slightly greater than 1. For simplicity and conservativeness in calculations, the value was equaled to 1 in equations (6).

Rearranging terms and assuming choked conditions in (3)

$$Q_{CH4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{1 - \frac{1}{3 * F_{CH4}}}{1 - \frac{1}{3 * F_{AIR}}} \quad (7)$$

The following are the assumptions used to state conservativeness in the approach.

a) Equation (2) is used to show all the possible pressure drops that can be experienced by the device before it reaches the critical pressure and then asymptotes under choked conditions.

b) Under choked conditions, $x=X_T$. **Choked flow** is a limiting condition which occurs when the mass flow rate will not increase with a further decrease in the downstream pressure environment while upstream pressure is fixed. Using equation (3), for air Y=0.667 and natural gas Y=0.643, so $Y_{CH4}/Y_{AIR} = .965$ in equations (6) and consequently (7). Under unchoked conditions and the extreme right-hand side of Figure A.1 (for $F_k=1.00$ and $x_{vc}=0.0$), $F_{CH4} = .935$ and $F_{AIR} = 1$, so it follows that $Y_{CH4}/Y_{AIR} = 1$. Note that Y_{AIR} and Y_{CH4} have been normalized with respect to Y_{AIR}. As can be seen, Y_{CH4}/Y_{AIR} drops from 1 in unchoked conditions to .965 in choked conditions. So by assuming choked conditions, the quantities are discounted at .965 and not 1. The approach "loses" 0.035 (1-.965) of the possible credits claimable, so it underestimates the quantities by

3.5% and provides a conservative approach. Table A.2 summarizes the calculations for Y_{CH4}, Y_{AIR} and x/x_T using equations in the ISA standard. The yellow row indicates choked conditions. Note that x_T is the terminal or limiting pressure where choking begins.

TABLE A.1 Evolution of Y_{CH4}/Y_{AIR} from unchoked to choked conditions

x/x_T	Y_{CH4} k=1.31	Y_{AIR} k=1.4	Y_{CH4}/Y_{AIR}
0	1	1	1
0.1	0.964	0.967	0.998
0.2	0.929	0.933	0.995
0.3	0.893	0.9	0.992
0.4	0.858	0.867	0.989
0.5	0.822	0.833	0.986
0.6	0.786	0.8	0.983
0.7	0.751	0.767	0.980
0.8	0.715	0.733	0.975
0.9	0.679	0.7	0.971
1	0.644	0.667	0.966

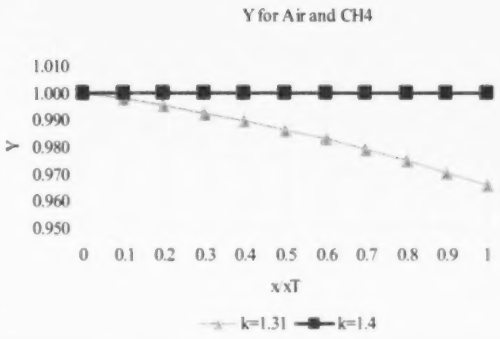


FIGURE A.1 Y for Air and CH4 (Normalized with respect to air)

c) From the figure in TABLE A.2, it is clear that by dividing methane as it asymptotes by the reference gas (with a value of $Y_{AIR}/Y_{AIR} = 1$), the minimum value will occur when choked conditions occur, or when F_{CH4} asymptotes at .965.

Specific gas gravities for greenhouse gases present in fuel supply gas at NTP[2] are summarized below.

TABLE A.2 Specific gravity of gases present in fuel gas

Gas	S.G.
Air	1.000
Carbon dioxide	1.519
Methane	0.5537
Natural Gas	0.60 - 0.70

Source: http://www.engineeringtoolbox.com/specific-gravities-gases-d_334.html

Using G_{CH4}= .5537, G_{AIR}=1, and k=1.31 for pure methane, (7) becomes

$$Q_{CH4} = 1.2977 * Q_{AIR}$$

This represents the volumes of pure methane that would have been vented instead of air. In general terms, pure methane is not vented. Instead, vented gas composed mainly of methane and to a lesser extent carbon dioxide is vented. Consequently, the amount of

[2] Normal Temperature and Pressure is defined as air at 20°C (293.15 K, 68°F) and 1 atm (101.325 kN/m2, 101.325 kPa, 14.7 psia, 0 psig, 30 in Hg, 760 torr)

greenhouse gases that would have been emitted in the absence of air is adjusted as follows in terms of mass flow rate:

$$\dot{m}_{CH4} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} \quad (8)$$

where

$\dot{m}_{CH4}$ = CH_4 mass fluid flow rate
$\%CH_4$ = volume fraction of CH_4 in fuel supply gas;
ρ_{CH4} = methane density; and
and

$$\dot{m}_{CO2} = Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \quad (9)$$

where

$\dot{m}_{CO2}$ = CO_2 mass fluid flow rate
$\%CH_4$ = volume fraction of CH_4 in fuel supply gas;
$\%CO_2$ = volume fraction of CO_2 in fuel supply gas;
44 = molecular weight of CO_2; and
16= molecular weight of CH_4.

Conservativeness of Approach

ISO 10464-2:2006(E) Section 3.7 introduces the principle of conservativeness and guidance is given on its application:

"Use conservative assumptions, values and procedures to ensure that GHG [greenhouse gas] emission reductions or removal enhancements are not over-estimated.

As stated previously, the parameter that has the most effect on flow in pneumatic devices is Y, the expansion factor. The ISA standard (sections 8.3.4 to 8.3.7) states that for the evaluation of C_v for a pneumatic device, at least two points are needed that comply with the following conditions

1. $(Y*C_v)_1 \geq 0.97(YC_v)_0$ where $(Y*C_v)_0$ corresponds to $x \cong 0$; and

2. $(Y*C_v)_n \leq 0.87(Y*C_v)_0$

3. The test points are plotted on linear coordinates as ($Y*C_v$) vs. x and a linear curve fitted to the data The value of C_v for the specimen (device) shall be taken from the curve at x=0, Y=1. The value of x_T for the specimen shall be taken from the curve at $Y*C_v=0.667*C_v$.

$Y*C_v=0.667*C_v$ corresponds to the critical ratio of air, which is the medium (type of gas) most commonly used for compressible fluid testing. The equations in the ISA standard are all corrected with respect to air which allows for testing with different types of gases, not just air. The other value of interest with respect to this protocol is $YC_v=0.644*C_v$, or the corresponding x_T for methane.

FIGURE A.2 (with values in TABLE A.3) is an example of this plotting procedure to evaluate C_v and x_T[3]. C_v was taken as 35.52 as an example. Note that $x_{T\ CH4}$ (blue line) is slightly higher than $x_{T\ AIR}$ (red line) at all times, regardless of the C_v value because the slope (m) of the linear curve (line) is always negative thus guaranteeing that $x_{T\ CH4}$ will always be greater than $x_{T\ AIR}$.

TABLE A.3 Illustrative Example of $Y*C_V$ vs. x

		Y*Cv
x	Y	35.200
0.000	1.000	35.200
0.021	0.970	34.144
0.092	0.870	30.624
0.236	0.667	23.467
0.252	0.644	22.661

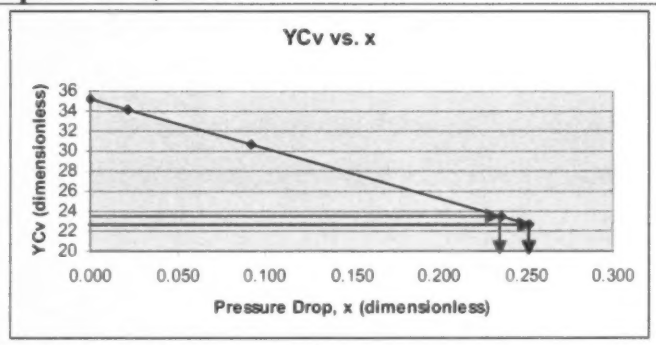


FIGURE A.2 Example of fitted data to linear curve

The value of $x_{T\ CH4}$ (=0.252) is slightly higher than $x_{T\ AIR}$ (=0.225) in this example. It is true that $x_{T\ CH4} \neq x_{T\ AIR}$ at all times because $x_{T\ CH4}$ will always be greater than $x_{T\ AIR}$. If this is assumed, then data can be generated for the expansion factors Y as summarized in TABLE A.4 and shown in FIGURE A.3. $x/x_{T\ CH4}$ and $x/x_{T\ AIR}$ are evaluated individually (i.e. $x_{T\ CH4} \neq x_{T\ AIR}$ is assumed). Note that if the pneumatic device runs on air, the maximum pressure drop it experiences is 0.225, which corresponds to Y_{AIR}= 0.667. The pressure drop if the device runs on CH_4 would be the same, which corresponds to Y_{CH4}= 0.682. Y_{CH4}/Y_{AIR} would be 0.682/ 0.667 or 1.022. It should be noted that air is flowing choked and CH_4 is flowing unchoked if the same pressure drop ratio is assumed. Therefore, air flow will enter choked conditions before CH_4 does at all times because $x_{T\ CH4} > x_{T\ AIR}$, regardless of C_V. If unchoked conditions are assumed also, this approach will increase the value of Y_{CH4}/Y_{AIR} from 1 to an asymptote of roughly 1.022.

[3] Example values taken from Stubbs, W.L. (1998). Establishing a new method for determining valve flow coefficient. Micro Magazine, May, p. 39-51.
Retrieved from http://www.micromagazine.com/archive/98/05/stubbs.html on 2008-08-06.

1.022 is higher than the one calculated assuming $x_{T\ CH4} = x_{T\ AIR}$, which corresponds to $Y_{CH4}/Y_{AIR} = 0.644/0.6667$ or .966. The value of .966 is conservative because it underestimates the actual value of quantifiable emissions (which would use 1.022 if $x_{T\ CH4} \neq x_{T\ AIR}$). Conclusively, assuming $x_{T\ CH4} = x_{T\ AIR}$ both under choked conditions simplifies and reduces calculations, and further metering requirements while assuring conservativeness as per ISO guidance.

Note on Pressure Drop, x

Typically, pneumatic devices are designed to operate at 20 PSI (~138 kPa) or 35 PSI (~241 kPa). The pressure drop, x (dimensionless), defined by the ISA standard is the ratio of pressure drop to absolute inlet pressure ($\Delta p/p_1$). Δp is the differential pressure, p_1-p_2. p_1 is the upstream absolute static pressure, measured two nominal pipe diameters upstream of the valve-fitting equipment. p_2 is the downstream absolute static pressure, measured six nominal pipe diameters upstream of the valve-fitting equipment. To approximate x in a field setting, p_1 can be assumed to be the design pressure and p_2 the atmospheric pressure at sufficient distance downstream. Therefore, x can be calculated as

$$x_{138kPa} = \frac{138-101}{138} = .275;$$

$$x_{240kPa} = \frac{241-101}{241} = .581$$

These are typical x values to be found in the field. These can be normalized with respect to $x_{T\ CH4}$ or $x_{T\ AIR}$ if the values are known from the manufacture. However, this may be impractical and tedious to accomplish. The proposed approach simplifies and keeps a conservative approach, in line with the ISO principle.

TABLE A.4 Y with the conditions $x_{T\,CH4} = x_{T\,AIR}$ and $x_{T\,CH4} \neq x_{T\,AIR}$

x_T	CH4=0.252			AIR=0.225			Y_{CH4}/Y_{AIR}	Y_{AIR}/Y_{AIR}				Y_{CH4}/Y_{AIR}
x	x	x/x_T	Y_{CH4}	x	x/x_T	Y_{AIR}	($x_{TCH4}=x_{T\,AIR}$)		x	x/x_T	Y_{CH4}	($x_{TCH4}\neq x_{T\,AIR}$)
0.0	0.000	0.0	1.000	0.000	0.0	1.000	1.000	1.000	0.000	0.000	1.000	1.000
0.1	0.025	0.1	0.964	0.023	0.1	0.967	0.998	1.000	0.023	0.089	0.968	1.002
0.2	0.050	0.2	0.929	0.045	0.2	0.933	0.995	1.000	0.045	0.179	0.936	1.003
0.3	0.076	0.3	0.893	0.068	0.3	0.900	0.992	1.000	0.068	0.268	0.905	1.005
0.4	0.101	0.4	0.858	0.090	0.4	0.867	0.989	1.000	0.090	0.357	0.873	1.007
0.5	0.126	0.5	0.822	0.113	0.5	0.833	0.986	1.000	0.113	0.446	0.841	1.009
0.6	0.151	0.6	0.786	0.135	0.6	0.800	0.983	1.000	0.135	0.536	0.809	1.011
0.7	0.176	0.7	0.751	0.158	0.7	0.767	0.979	1.000	0.158	0.625	0.777	1.014
0.8	0.202	0.8	0.715	0.180	0.8	0.733	0.975	1.000	0.180	0.714	0.746	1.017
0.9	0.227	0.9	0.679	0.203	0.9	0.700	0.971	1.000	0.203	0.804	0.714	1.020
1.0	0.252	1.0	0.644	0.225	1.0	0.667	0.966	1.000	0.225	0.893	0.682	1.023

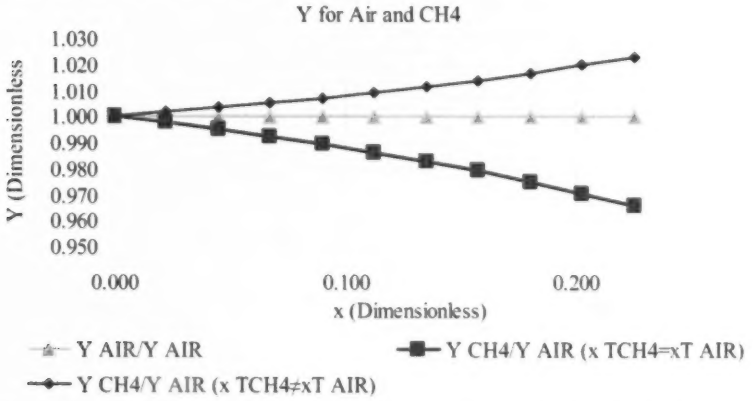


FIGURE A.3 Expansion Curves for Y_{CH4}/Y_{AIR} $x_{T\,CH4} = x_{T\,AIR}$ and $x_{T\,CH4} \neq x_{T\,AIR}$

A.2 Leaks

Minimizing leaks by making use of a regular inspection and maintenance program ensures that metered air volumes are not overestimated, and hence gas that would have been vented had the instrument air conversion not taken place. At times a regular inspection and maintenance program is not practical or programmed at different time periods that do not coincide with the implementation of the instrument air conversion project. Estimates based on best practices and emission factors from credited references are used to discount metered air volumes to safeguard conservativeness in these estimations.

The discount factors presented here are based on rates from the EPA's Natural Gas STAR Program *Lessons Learned-Convert Gas Pneumatic Controls to Instrument Air.* Instrument control devices in service and that have not been repaired will leak as time passes. A 2.5 % yearly linear increase in leaks is assumed. For devices that have been recently inspected and repaired, the discount rate is assumed to be zero. For devices or pipe networks that have not been inspected and repaired in the last 10 years, the discount rate increases linearly until reaching25%. The maximum discount rate is 25% for devices with more than 10 years without inspection and repairs. The equations used to calculate the discount rate are as follows:

$$DR\ (\%) = 2.5\ \% * (\text{minimum year interval}) \quad \text{for } 0 < \text{year} < 10 \tag{10}$$

$$DR\ (\%) = 25\% \quad \text{for year} > 10 \tag{11}$$

This relationship is assumed linear and is illustrated in Figure A.1. As an example, if the last inspection and repair took place 5.5 years ago, then the minimum of that year interval is 5.5 times 2.5 % yearly increase due to leaks yields a 12.5 % leak rate. The DR is therefore 12.5%.

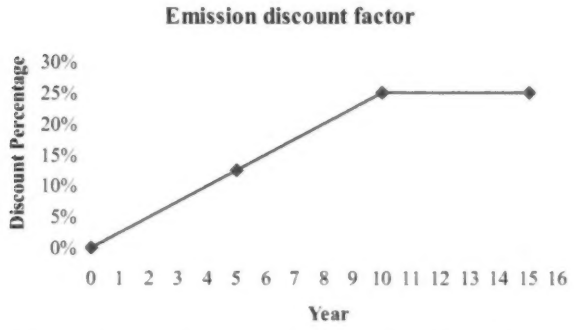


Figure A.4 Linear relationship between elapsed time and discount factor.

This discount rate is used to adjust the baseline and maintain a conservative approach. Equations (10) and (11) are incorporated into equations (8) and (9) as coefficients as illustrated in the following equations:

$$\dot{m}_{CH4} = (1 - DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} \quad (12)$$

$$\dot{m}_{CO2} = (1 - DR) * Q_{AIR} * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16} \quad (13)$$

APPENDIX B - Quantification Procedures for Flexibility Mechanisms

B.1 Retroactive Credits

To facilitate verification of retroactive credits, the project proponent should identify the run time of principle equipment such as compressors, dehydrators, or other equipment within the facility, or provide other facility-specific supporting documentation to demonstrate continuity of operations. In the event that instrument counts cannot be developed for a facility in the past, the proponent can use the aforementioned evidence to demonstrate that a significant change to the facility had (or had not) occurred.

The project developer will then use the baseline and project quantities metered during the one year metering period and adjust those using engineering calculations to reflect emissions in the unmetered period. Adjustments are based on instrument counts and vent rates from the manufacture's technical specifications. The pneumatic device's vent rate is adjusted for leak inspection and repair, and then multiplied by the complete hours of operation (i.e. 8,760 hours per year). Finally, this value is subtracted from the measured baseline as follows:

$$BE' = BE * t - \sum_{i=1}^{n} VR_i * (1 + DR_i) * t_i$$

where

BE' = adjusted baseline emissions from time project was implemented to time when project was metered (tCO_2e);
t = time of project implementation (hours);
BE = metered emissions from project (tCO_2e);
VR_i = vent rate of instrument i using manufacture's technical specifications (m^3/h);
DR = leak discount rate (%); and
t_i = time from installation of instrument to time when project was metered (hours).

This method uses measured amounts and adjustments based on a conservative approach. By assuming complete hours of operation (i.e. 8,760 per year) for the unmetered period and adding instead of subtracting the DR, the retroactive emissions are underestimated and as a result the net offsets claims are also underestimated.

As an example, a project was implemented 4 years ago but was not metered and no inspection for leaks or repairs occurred. If the baseline emissions were calculated at BE after the first year of metering, and 1 instrument (Type A with 6 scmh emission rate) was placed 3 years ago, the BE' would be

$$BE_{AIR}' = BE_{AIR} * (4 * 8.760) - \sum_{i=1}^{1} 6_i * (1 + 7.5\%_i) * (4 * 8{,}760)_i$$

B.2 Fraction of Vented and Combusted Emissions

Vent and bleed natural gas may be collected and sent to a flare or other combustion sources for various reasons. Therefore this protocol allows the project developer to claim

credits from combusted and vented gas. The vent or bleed gas fraction X is estimated as follows based on vendor's technical specifications:

$$X = \frac{\sum_{i=1}^{n} VR_i * n_i}{\sum_{i=1}^{n} VR_i * n_i + \sum_{j=1}^{m} VR_j * m_j}$$

where

VR_i= vent rate for device i from manufacturer's technical specifications that vent gas to the atmosphere;
n_i = number of type i devices;
VR_j = vent rate for device j from manufacturer's technical specifications for gas that is combusted;
m_j = number of type j devices;

The denominator is simply the addition of all devices at the facility. The combusted emissions are the remaining fraction and are calculated as:

$$1 - X = 1 - \left(\frac{\sum_{i=1}^{n} VR_i * n_i}{\sum_{i=1}^{n} VR_i * n_i + \sum_{j=1}^{m} VR_j * m_j} \right)$$

Care must be taken to use bleed rates that are either expressed in terms of air or natural gas as well as the same units.

1. Project / Baseline SS	2. Parameter/ variable	3. Unit	4. Measured/ estimated	5. Contingency Method	6. Frequency	7. Justify measurement or estimation and frequency
Flexibility Mechanism						
B6 Vented Fuel Gas	*The following equations are used to establish baseline emissions based on metered compressed air powering the pneumatic instruments once the air conversion has taken place. Equation (1) is for the vented CH_4 and will always be used. Typically, the percentage of CH_4 in fuel gas is in excess of 85% and can be as much as 99%. Equation (2) is used to establish baseline emission for ventedCO_2. If the percentage of CO_2 is in excess of 10%, equation (2) is used to establish baseline CO_2 emissions from vented fuel. If the percentage of CO_2 emissions is inferior to 10%, it is advisable not to include CO_2 emissions as the volumes are insignificant. Equations (3) and (4) are used to establish CO_2e emissions from flared fuel gas*					
	(1) Emissions $_{\text{Vented Fuel Gas}}$ = Σ Compressed Air $_{\text{Control Instruments i}} * X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4}$;					
	(2) Σ Compressed Air $_{\text{Control Instruments i}}$					

$$* X * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%CH_4 * \rho_{CH4} * \frac{\%CO_2}{\%CH_4} * \frac{44}{16};$$

where

$$F_k = \frac{k}{1.4}$$

(3) Emissions $_{\text{Flared/Combusted Fuel Gas}}$ =

$$\Sigma \text{ Compressed Air}_{\text{Control Instruments}}$$

$$_{i} * (1 - X) * (1 - DR) * \sqrt{\frac{G_{AIR}}{G_{CH4}}} * \frac{\left(1 - \frac{1}{3 * F_k}\right)}{\left(1 - \frac{1}{3 * F_{AIR}}\right)} * \%w * \frac{44}{12} * \%EF.;$$

where

w= average carbon content of fuel gas (kg C/m^3 fuel gas)[4]

Emissions $_{\text{Vented Fuel Gas}}$	kg of CH_4 ; CO_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
Emissions $_{\text{Flared/Combusted Fuel Gas}}$	kg of CH_4 ; CO_2	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregate for each of these SS's.
Compressed Air Used for Pneumatic Instruments $_i$/ Compressed Air $_{\text{Control Instruments i}}$	m^3	Measured	Direct metering of volume being compressed and sent to control instrument pipe network as determined in P6	1 year continuous metering	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
Fraction of vented emissions/ X	-	Estimated	Estimated using $X = \frac{\sum_{IR} * n}{\sum_{IR} * n - \sum_{IR} * m}$	N/A	This represents the fraction of vented emissions from control devices
Discount Rate due to Leaks / DR	%	Estimated	1. DR(%)=0 if inspection occurred ≤ 1 year 2. DR(%)= 2.5 %*minimum year interval	N/A	Leaks are taken into account when air is metered to adjust the baseline. The year of last documented inspection and

[4] The average carbon content of the fuel gas is used to calculate CO_2 emissions. Average carbon content can be calculated from the annual gas composition data of the fuel gas using a weighted average technique. Alternatively, the average carbon content can be determined from an elemental analysis of the gas itself using various methods available. Other methods are also applicable.

				for 1< year ≤ 10 3. DR(%)= 25% for year > 10		maintenance is taken into account in parameter 'year'.
	Specific Gravity of Air /G_{AIR}	-	Estimated	1.00 at NTP	N/A	Accepted value.
	Specific Gravity of Methane / G_{CH4}	-	Estimated	0.5537 at NTP	N/A	Accepted value.
	Density of Methane / ρ_{CH4}	Kg / m^3	Estimated	0.717kg/m^3 at STP	N/A	If this value is used all values must be adjusted for standard temperature and pressure.
	Specific Heat Ratio for CH_4 / k_{CH4}	-	Assumed	1.31 at STP	N/A	Accepted value
	Specific Heat Ratio for air /1.4	-	Assumed	1.40 at STP	N/A	Accepted value
	Methane Composition in Fuel Gas / % CH_4	-	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation
	Carbon Dioxide Composition in Fuel Gas / % CO_2	-	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation
	Carbon Compound with n number of carbon molecules in fuel gas/ C_n	%	Measured	Direct measurement	Annual	Fuel gas composition should remain relatively stable during steady-state operation
	Flare Destruction Efficiency/ %EF	%	Estimated	From accredited sources such as CAPP or API	-	Provides reasonable estimate of the parameter, by accredited sources[5]

B.3 Discounting or Adding Devices due to decommissioning and commissioning or other uses for air.

If devices are decommissioned after the implementation of the project, the baseline will be altered and the metered air may reflect higher vented fuel volumes once the gas equivalency has been applied. To avoid overestimating the baseline, the baseline is

[5] A destruction efficiency of 98% is typically reported in literature. Refer to Canadian Association of Petroleum Producer's (CAPP) Guide –Calculating Greenhouse Gas Emissions (April 2003) section 1.7.3 for more guidance.

reduced by a factor equal to the sum of the decommissioned devices as illustrate in the following equation

$$Q_{AIR}' = Q_{AIR} - \sum_{i=1}^{n} CR_i * n_i$$

where
CR_i= consumption rate for device i from manufacturer's technical specifications;
n_i = number of type i devices;

Consumption rates for pneumatic devices are termed bleed rates (BR). The following tables list bleed rates (BR) from devices commonly used in the field. These rates are expressed in terms of natural gas. An inverse application of gas equivalency should be used to adjust metered air volumes.

The opposite may occur when after metering, devices are commissioned. If devices are commissioned after the implementation of the project, the baseline will be altered and the metered air may reflect lower vented fuel volumes once the gas equivalency has been applied. To avoid underestimating the baseline, the baseline is increased by a factor equal to the sum of the commissioned devices as illustrate in the following equation

$$Q_{AIR}' = Q_{AIR} + \sum_{i=1}^{n} CR_i * n_i$$

This is also applicable for devices during the metered period that do not contribute to instrument process control. Such devices consume air and if metered would reflect higher air and therefore vented gas. These devices should be discounted from the metered air as shown in the previous equation before applying the gas equivalency formula.

Instrument Characteristics[6]

TABLE 1: Bleed Rates for Pneumatic Devices Used in the Oil and Gas Industry

Controller Model	Signal Pressure (Psi)	Manufacturer Data (scfh)
Pressure Controller		
Ametek Series 40	20	6
	35	6
Bristol Babcock Series 5453-Model 10F	20	3
	35	3
Bristol Babcock Series 5455-Model 624-III	20	2
	35	3
Bristol Babcock Series 502 A/D (recording controller)	20	<6
	35	<6
Fisher 4100 Series (Large Orifice)	20	50
	35	50
Fisher 4150 and 4160	20	10 – 35
	35	10 - 42
Fisher 4194 Series (Differential Pressure)	20	3.5
	35	5
Fisher 4195	20	3.5
	35	5
Foxboro 43AP	20	18
	35	18
ITT Barton 338	20	6
	35	6
ITT Barton 335P	20	6
	35	6
Natco CT	20	35
	35	35
Transducers		
Bristol Babcock Series 9110-00A	20	.42
	35	.42
Fisher 546	20	21
	35	30
Fisher 646	20	<1
	35	<1
Fisher 846	20	<1
	35	<1
Level Controllers		
Fisher 2900	20	23
	20	23
	35	23
	35	23
Fisher 2500	20	42
	35	42
Fisher 2660 Series	20	1

[6] Source: CETAC-West Efficient (May, 2008). Use of Fuel Gas in Pneumatic Instruments Module 3 of 17 (Refer to original manufacturer's product information data sheet for more accurate information on product performance.

	35	1
Fisher 2100 Series	20	<1
	35	<1
Fisher 2680	20	<1
	35	<1
Fisher L2		
Invalco CT Series	20	
	35	40
Norriseal 1001	20	N/A
	35	N/A
Norriseal 1001 (A)	20	0.007
	20	0.2
	35	0.007
	35	0.2
Wellmark 2001	20	0.007
	20	0.2
	35	0.007
	35	0.2
Positioners		
Fisher 3582	20	14
	35	18
Fisher 3661	20	8.8
	35	12.1
Fisher 3590 (Electro-pneumatic)	20	24
	35	36
Fisher 3582i (Electro-pneumatic)	20	17.2
	35	24
Fisher 3620J (Electro-pneumatic)	20	18.2
	35	35
Fisher 3660	20	6
	35	8
Fisher Fieldvue Digital	20	14
	35	49
Masoneilan 4600B Series	20	
	35	18 - 30
Masoneilan 4700B Series	20	
	35	18 - 30
Masoneilan SVI Digital	20	<1
	35	<1
Masoneilan 7400 Series	20	24 – 50
	35	24 - 50
Moore Products – Model 750P	20	
	35	42
Moore Products – 73 – B PtoP	20	36
	35	
PMV D5 Digital	20	<1
	35	<1
Sampson 3780 Digital	20	<1
	35	<1
VRC Model VP7000 PtoP	20	<1
	35	<1

TABLE 2: Gas-Driven Pneumatic Device CH_4 Emission Factors by Segment[7]

Device Type	Emission Factor (Original Units)	Precision (+%)	CH4 Emissions Factor* (Converted to Tonnes Basis)
Production Segment			
Continuous bleed	654 scfd gas/device	31	Based on 78.8 mole % CH_4 3.608 tonnes/device-yr
Intermittent bleed	323 scfd gas/device	34	1.782 tonnes/device-yr
Production Average (if device type is unknown)	345 scfd CH_4/device	40	2.415 tonne I/P Positioner
Transmitter (140 kPag)	0.12 m3 gas/hr/device	Precision not specified	0.56 tonnes/device-yr
Transmitter (240 kPag)	0.2 gas/hr/device		0.94 tonnes/device-yr
Controller (140 kPag)	0.6 gas/hr/device		2.8 tonnes/device-yr
Controller (240 kPag)	0.8 gas/hr/device		3.7 tonnes/device-yr
Controller (pressure not specified)	.1996 gas/hr/device		0.9332 tonnes/device-yr
I/P Transducer (140 kPag)	0.6 gas/hr/device		2.8 tonnes/device-yr
I/P Transducer (240 kPag)	0.8 gas/hr/device		3.7 tonnes/device-yr
P/P Positioner (140 kPag)	0.32 gas/hr/device		1.5 tonnes/device-yr
P/P Positioner (240 kPag)	0.5 gas/hr/device		2.3 tonnes/device-yr
I/P Positioner (140 kPag)	0.4 gas/hr/device		1.9 tonnes/device-yr
I/P Positioner (240 kPag)	0.6 gas/hr/device		2.8 tonnes/device-yr
Processing			
Continuous bleed	497,584 scf gas/device-yr	29	Based on 87 mole % CH_4 8.304 tonnes/device-yr
Piston valve operator	48 scf gas/device-yr	49	8.0101E-04 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	112	0.0939 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	276	1.128 tonnes/device-yr
Processing average (if device type is unknown)	164,949 scfy gas CH_4/plant	113	3.160 tonnes/plant-yr
	7,454 scf CH_4/MMscf processed		
Transmission and Storage			
Continuous bleed	497,584 scf gas/device-yr	29	Based on 93.4 mole % CH_4 8.915 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	112	0.1008 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	276	1.211 tonnes/device-yr
Transmission or storage average	162,197 scfy gas CH_4/device	44	3.111 tonnes/device-yr
Distribution			
Pneumatic isolation valves based on 93.4 molc% CH_4	0.366 tonnes CH_4/device -yr	Precision not specified	0.366 tonnes /device -yr
Pneumatic control loops based on 93.4 molc% CH_4	3.465 tonnes CH_4/device -yr	Precision not specified	3.465 tonnes /device -yr
Distribution average (if device is unknown) based on 93.4 molc% CH_4	2.941 tonnes/device-yr	Precision not specified	2.941 tonnes/device-yr

* CH_4 emission factors converted from scf and m^3 are based on 60°F and 14.7 psia.

[7] Source: American Petroleum Institute (February, 2004). Compendium for Greenhouse as Emissions Methodologies for the Oil and Gas Industry. Table 5-15.

TABLE 3: Gas Consumption Rates (m^3/h) For Standard (High Bleed) Pneumatic Instruments

Instrument	Operating Pressure (140 kpag)	Operating Pressure (240 kpag)
Transmitter	0.12	0.2
Controller	0.6	0.8
I/P Transducer	0.6	0.8
P/P Positioner	0.32	.05
I/P	0.4	0.6
Chem. injection pumps (diaphragm)	0.4	0.6
Chem. injection pumps (piston)	0.04	0.06

APPENDIX C - Emissions Factor for Selected Fuels[8]

[8] Source: Environment Canada (2006). NATIONAL INVENTORY REPORT, 1990-2005: GREENHOUSE GAS SOURCES AND SINKS IN CANADA. (Subject to Updates-Project developers should contact Environment Canada for the latest factors).

Relevant Emission Factors

TABLE B.1: Emission Intensity of Fuel Extraction and Production (Diesel, Natural Gas and Gasoline)

Diesel		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre
Natural Gas		
Extraction		
Emissions Factor (CO_2)	0.043	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0023	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000004	kg N_2O per m^3
Processing		
Emissions Factor (CO_2)	0.090	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0003	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000003	kg N_2O per m^3
Gasoline		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre

TABLE B.2: Emissions Factors for Natural Gas and NGL's

Source	Emissions Factor		
	CO_2	CH_4	N_2O
	g/m^3	g/m^3	g/m^3
Natural Gas			
Electric Utilities	1891	0.49	0.049
Industrial	1891	0.037	0.033
Producer Consumption	2389	6.5	0.06
Pipelines	1891	1.9	0.05
Cement	1891	0.037	0.034
Manufacturing Industries	1891	0.037	0.033
Residential, Construction, Commercial/Institutional, Agricultural	1891	0.037	0.035
	g/L	g/L	g/L
Propane			
Residential	1510	0.027	0.108
All Other Uses	1510	0.024	0.108
Ethane	976	N/A	N/A
Butane	1730	0.024	0.108

TABLE B.3: Emissions Factors for Refined Petroleum Products

Source	Emissions Factor (g/L)		
	CO_2	CH_4	N_2O
Light Fuel			
Electric Utilities	2830	0.18	0.031
Industrial	2830	0.006	0.031
Producer Consumption	2830	0.006	0.031
Residential	2830	0.026	0.006
Forestry, Construction, Public Administration, and Commercial/Institutional	2830	0.026	0.031
Heavy Fuel Oil			
Electric Utilities	3080	0.034	0.064
Industrial	3080	0.12	0.064
Producer Consumption	3080	0.12	0.064
Residential	3080	0.057	0.064
Forestry, Construction, Public Administration, and Commercial/Institutional	3080	0.057	0.064
Kerosene			
Electric Utilities	2550	0.006	0.031
Industrial	2550	0.006	0.031
Producer Consumption	2550	0.006	0.031
Residential	2550	0.006	0.031
Forestry, Construction, Public Administration, and Commercial/Institutional	2550	0.006	0.031
Diesel	2730	0.133	0.4

APPENDIX D

Specified Gases and Global Warming Potential

Specified Gases and Their Global Warming Potentials

Specified Gas	Chemical Formula	Global Warming Potential (100 year time horizon)
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous oxide	N_2O	310
HFC-23	CHF_3	11700
HFC-32	CH_2F_2	650
HFC-41	CH_3F	150
HFC-43-10mee	$C_5H_2F_{10}$	1300
HFC-125	C_2HF_5	2800
HFC-134	$C_2H_2F_4$	1000
HFC-134a	CH_2FCF_3	1300
HFC-152a	$C_2H_4F_2$	140
HFC-143	$C_2H_3F_3$	300
HFC-143a	$C_2H_3F_3$	3800
HFC-227ea	C_3HF_7	2900
HFC-236fa	$C_3H_2F_6$	6300
HFC-245ca	$C_3H_3F_5$	560
Sulphur hexafluoride	SF_6	23900
Perfluoromethane	CF_4	6500
Perfluoroethane	C_2F_6	9200
Perfluoroproprane	C_3F_8	7000
Perfluorobutane	C_4F_{10}	7000
Perfluorocyclobutane	c-C_4F_8	8700
Perfluoropentane	C_5F_{12}	7500
Perfluorohexane	C_6F_{14}	7400